ALASKA STATE LEGISLATURE
JOINT MEETING
LEGISLATIVE BUDGET AND AUDIT COMMITTEE
SENATE RESOURCES STANDING COMMITTEE
June 17, 2004
8:45 a.m.
DRAFT

MEMBERS PRESENT

LEGISLATIVE BUDGET AND AUDIT

Representative Ralph Samuels, Chair
Representative Mike Hawker
Representative Beth Kerttula
Representative Reggie Joule
Representative Mike Chenault (via teleconference)

Senator Con Bunde
Senator Lyman Hoffman

SENATE RESOURCES

Senator Scott Ogan
Senator Tom Wagoner
Senator Fred Dyson

OTHER MEMBERS PRESENT

Senator Gretchen Guess

MEMBERS ABSENT

LEGISLATIVE BUDGET AND AUDIT

Representative Vic Kohring

Senator Gene Therriault, Vice Chair
Senator Gary Wilken
Senator Ben Stevens

SENATE RESOURCES

Senator Ben Stevens
Senator Ralph Seekins
Senator Georgianna Lincoln
Senator Kim Elton

COMMITTEE CALENDAR

Alaska Natural Gas Pipeline Issues/Pipeline Costs & Tariffs

Presentations By:

Mr. Harold Heinze, Chief Executive Officer, Alaska Natural Gas Development Authority

Mr. Roger Marks, Petroleum Economist, Tax Division, Alaska Department of Revenue

Mr. John Carruthers, Vice President, Northern Development, Enbridge Pipelines, Inc.

Mr. Robin Brena, Partner, Brena, Bell & Clarkson, P.C.

Mr. Tony Palmer, Vice President, Alaska Business Development, TransCanada Corporation

ACTION NARRATIVE

TAPE 04-9a, SIDE A [BUD TAPE][**SIDE B** IS NOT RECORDED]

CO-CHAIR RALPH SAMUELS called the joint meeting of the Legislative Budget and Audit Committee and the Senate Resources Standing Committee to order at 8:45 a.m. Senate Resource Committee members Tom Wagoner, Fred Dyson, and Scott Ogan, Chair, were present. Legislative Budget and Audit Committee members Con Bunde, Lyman Hoffman, Mike Hawker, Beth Kerttula and Reggie Joule were present. Senator Gretchen Guess and Representative Bill Stoltze were also present.

CO-CHAIR SAMUELS announced that Mr. Heinze would present to the committee first. He informed members that Mr. Heinze is the CEO of the Alaska Natural Gas Development Authority (ANGDA) and has been involved in North Slope gas issues for over 30 years. He was ARCO’s engineering manager of the Prudhoe Bay field start-up in 1977 and was the President of ARCO-Alaska and ARCO Transportation during the 1980s. During the Hickel Administration, he was the commissioner of natural resources and the state-to-gas marketer.

MR. HAROLD HEINZE, Chief Executive Officer of ANGDA, jested that he has appeared before legislative committees many times in the last few years but this is the first time he is appearing without requesting any money. He told members that he is not an expert on tariff issues; instead he will discuss cost related issues and the elements that go into a tariff determination. He said he would focus on the in-state issues because ANGDA's interest is what happens within Alaska. He then gave a PowerPoint presentation [paper copy available in committee file], with the following explanation.

> Number one, this is sort of the slide J.P. Morgan showed you yesterday of a number of things that go into the tariff and, in particular...the goldish color were the ones they talked about the sensitivity and gave you some results. I'm going to talk mainly about the ones that are circled in red and then I think between myself and Roger Marks, who follows me, we'll pretty well will have covered about every arrow on the page here by the end of the three or four presentations. Additionally, I'm going to give you some thoughts that we have, from our point of view, in terms of some of the projects we're looking at in terms of the relationship between debt-equity ratio and the bond rate and how that might affect the tariffs.
>
> Here [indisc.] is the outline. I hope it's not too daunting but I intend to go through it pretty fast and we can come back and spend time wherever you wish. Number one, I just wanted to make sure we understood ANGDA now is working on three basic things, the first of which, of course, is as prescribed in the ballot measure was to look at an LNG project and we are.
>
> Secondly, we've been asked by the Administration, as part of the broad Administration effort but separate from the Stranded Gas Act work that's going on, to look at ways that ANGDA as a public corporation of the state might be helpful in moving forward any of the highway gas line projects and there are ideas we have there in terms of how the state might participate and facilitate the project moving forward.
>
> And then finally, we've been asked very specifically to even go beyond the spur line requirement of ballot measure 3 and look very specifically at how we might get gas to Cook Inlet. Right now, as required in ballot measure 3, there is a requirement that was actually – we passed a couple of days ago, on June 15th

to issue a report, a development plan, competency in about 11 different items. We're frankly late on that. We're going to do that by about mid-August. We believe that is a reasonable timeline. In addition, we'll put out at that same time a report on how we believe Cook Inlet gas or North Slope gas could be brought to Cook Inlet.

To put it in perspective for you here, I listed out a list of the projects that I'm sort of aware of and the price tags that are thrown out as being associated with them. You heard yesterday from the Port Authority with their Y-line concept that weighs in at about $26 billion. The producers have talked about a highway gas line, very large in diameter, maybe 52 inches, down through Canada and all the way to Chicago for about $19 billion. We've heard from Enbridge and a little bit from TransCanada at this point of maybe a little more modest highway project weighing in at about $15 billion to Alberta. If you remember back, Yukon Pacific had described an LNG project for about $12 billion out of Valdez. The one we're looking at would be about $10.5 billion. Additionally, a number of years ago, some Cook Inlet companies and some North Slope companies looked at a project for 1 billion cubic feet a day out of Cook Inlet and that was a little under $7 billion. We are looking at a concept of a bullet line - a small line direct from the North Slope to Cook Inlet and that would weigh in at about $2 to $3 billion and, additionally, we're looking at the spur line.

ANGDA itself, as you can see by the chart, is tending to look at the lower side and the very Alaska side of these issues, not to say we don't try to learn from and keep up with what's going on in the other projects and, frankly, look for ways to interact with them because, for instance, the concept of a spur line – who gets the gas to where – is a very important part of that notion.

But this is kind of the suite and even though the focus of this hearing and the focus of everybody's effort is very clearly at that producer project at $19 billion, it's very important that you realize all of these other potential projects are on the table. And the reason, simply put, is a $19 billion project that requires the approval of a half-dozen to a dozen entities has a chance factor of actually going forward but it's kind of low, and so you have to have other projects in the screen or we're going to end up sort of hitting the wall, being stopped, and having nothing to do at that point.

The LNG project in particular that we're looking at is portrayed on this chart. Keeping in mind that a gas conditioning facility and the first 530 miles of pipeline is common to almost everybody's project. This one happens to be a 36 inch line, which is the same size, for instance, that Enbridge proposed for going down the highway. But it is definitely smaller than what the producers have talked about.

The liquefaction trains here are very large. They reflect the latest kind of a technology that's been in use. There is capital money included for a tanker fleet that is a mixture of foreign flag and Jones Act. And, again, we don't intend to own those tankers. We would contract for them basically. But to get a feel for the cost of service and to be comparable to other projects that deliver to a market, we felt it was important to include the money.

The other basic piece of ANGDA's work in looking at the LNG project has to do with the benefits diagram and a number of you have seen this before. In addition to just measuring a project's return in terms of just dollars to the State of Alaska, you have to look at the full suite of these benefits. We have just completed, and it is now available publicly, a benefits model, a huge spreadsheet model that incorporates not only the revenue side, but all the whole economic impacts and all the other things. In addition you'll notice in here we've included the provision for moving gas to the coastal communities, moving gas for LPG to the river communities of Alaska. We think that's a very important part of it. So that is the totality of our focus.

It turns out that when we look at all these issues, our business model is very clear. If we can provide the lowest cost of service, delivery of gas, that is good for everybody. It encourages everything good to happen on the North Slope. It encourages everything good to happen in Alaska in terms of our own consumers, our own industries, everything else and, frankly, it's good for the ultimate customer down in the Lower 48 or across the seas.

If you take the $10.5 billion that we're looking at in our capital cost and recognize that it's a 2 billion cubic feet a day project, we go through a calculation of a cost of service. This is similar to the kinds of calculations you saw yesterday from J.P. Morgan. I've shown two cases here. The top one is a 30-70 split on equity to debt and a 12 percent return on equity and an 8 percent bond rate basically on debt. And you can see the calculation here would yield $2.51. Again, the way you use this kind of chart notionally is then you would add to that a wellhead value, let's say it's a dollar - or 99 cents to keep the arithmetic easy – getting $3.50. You could then compare that $3.50 to your expectation of price in the market. If you expected a $3.50 price in the market, what that would say is that you have a project that can realize 99 cents at the wellhead and still yield a 12 percent return on equity and pay a debt rate of 8 percent.

And the alternative, if you change the debt-equity structure and you make some different assumptions on what the bond rate is, that number goes down in this case to $1.94. And again, all these calculations have been made using a model that was developed and is available publicly from Roger Marks in the Department of Revenue. I've used that as the base model for all our calculations. It is also the model that is embedded in our benefits spreadsheet model and everything else. And, very frankly, I would encourage apples to apples that while people might want to look at projects other ways, it's kind of helpful if they do the calculation also with this model so we can get a handle. And that's why I showed you the second column on this. This is the producers' $19 billion project plugged into the same model and this is the result it yields. You'll notice it's a slightly lower cost of service to Chicago and it has some other characteristics that are positive. Again, we think it's very important to explore all of those issues and see how they fit together.

I guess I wanted to just add a little bit of a flavor here. As ANDGA looks at this, it is our belief that for smaller projects that are undertaken by a state public corporation acting as a utility, we could achieve very high debt rates and very low bond rates on those. Now, certainly for bigger projects measuring in the 10s and 20 billions of dollars, I think the advice you heard probably yesterday from J.P. Morgan is more indicative. But we still believe that something in this range of say 70 percent debt-equity ratio is very achievable. We believe also that the state has also probably more modest equity considerations than others. And I'll show you how that comes into play towards the end of this presentation.

I did want to reflect to you a couple things that are going on and, again, just in a general sense, say to you this is why you need to keep revisiting this issue because I know the legislature visited very heavily two-three years ago the gas issue. Well, I hate to break it to you, but the world's changed and that's what this chart shows. Up until several years ago the United States, because of the great excess of gas supply to demand, had the lowest price in the world for gas. What we've seen is that supply go away. We've seen the price rise as you would expect and, more importantly, we're seeing the world price of gas converge. All those dynamics are very powerful. One of the things in that convergence is LNG and moving gas between various producing countries all around the world to various marketplaces and we should see some equilibrating of that price, very similar to what happened to oil.

Now we don't necessarily believe a 'gas PEC' or a 'G-PEC' will form that fulfills that same function of supply demand price balance but it is very clear that the five mega-major oil companies, British Gas and maybe a couple of the Japanese trading companies, will be the major players controlling that gas flow and it's reasonable to expect that we will see something happen that is not unlike what happened on oil.

Again, we have looked at our project compared to the projects around the world. Certainly we understand why, for instance, British Petroleum and Indonesia may choose to develop that gas and move it as LNG to Baja, California. Those are things that each of the companies, each of the players in this, will make an analysis. One of the more interesting comparisons we would point out to you is that Shell, who does not have any Alaska gas, is a major player in LNG, and they chose, without any contracts or any other commitments to develop Sakhalin - and Sakhalin is, by comparison to our LNG project, Sakhalin is $10 billion for 1.3 billion cubic feet a day, - and if you think about our project as...$10.5 billion for 2 billion cubic feet a day, you can see that we probably compare very favorably in terms of economics. And that's what our broad look says, is that broadly we are in the pack. We are certainly not the highest cost. We are certainly not the lowest cost but we can compete, we believe, with all these projects.

Also there are some distance advantages we enjoy to the West Coast and some of those may be difficult to capture if we act exactly like the mega-major oil companies. The great part of being ANGDA is as this public corporation of the state, we don't have to act like the mega-majors, we can look for other ways to compete in the marketplace with them that are different than their strategies. And again, we don't have a portfolio of projects. We have basically one project and we have to find a way to make it work.

On the LNG scene, there's also some very good news. What we've seen is a dramatic decrease in the unit cost to build these plants and liquefy the natural gas. And again, I've identified the source of this chart. I left BP's identity on it. It was presented in Washington, D.C. about six, seven months ago. So I mean it's very recent information. It's very real. Almost everybody has observed this trend. One of the things we will do by August is validate the trend and validate whether it is applicable to our situation here in Alaska. This makes the difference, this chart, between an LNG plant that costs $2 billion, $3 billion or $4 billion. I've taken the conservative approach of using only $3 billion right now but potentially if I took this chart at its face value we could write down $2 billion for that. Those kinds of cost savings dramatically alter your economics.

Additionally, the world trade right now in terms of LNG tankers with all the number of tankers being built in a wide variety of places around the world, there's a very definite trend downward and how that translates for us, how the Jones Act issues get worked, is going to be a subject of our report. We're very cognizant of those issues. But this is a very favorable trend and, again, this is from the Department of Energy so I have every reason to believe the U.S. Government's got this one right.

I wanted to take a minute and talk a little bit about pipelining costs and the reason is that everything you've heard over the last several days involves anywhere from $2, $3, $4 billion on up to $8, $10, $12 billion worth of pipeline and underlying those costs are cost estimates. And what I did was I pulled together here a whole series of estimates and actual costs covering a fairly wide spectrum of people's opinions on cost. For instance, the last time the legislature looked at this about three years ago, the detailed cost estimates that were made – tariff calculations and all that, were based on the concept of $140[,000] per inch diameter mile. In other words, what you do is you take the billions of dollars of cost, you divide by how many miles that pipeline is and by how many inches in diameter it is. It's a way of kind of equating different size pipelines, different lengths, and everything to one number. It's not certainly a requirement of science that they all be exactly the same but generally, in an estimating sense, one would expect them to be very similar. And in the past the number that was used was $140,000 per inch diameter mile. Well the producers, after spending $125 million, have published a number, which is $115,000 per inch diameter miles, and somebody forgot to say thank you to them because they just saved 25 percent of the cost of the pipeline. That's a significant reduction. Again, that makes a lot of difference in these numbers.

Now, at this point do we have any of the information that allows us to know if that's just a result of somebody else doing the estimate? And I will tell you as an engineer sometimes that happens. People estimate things different. Or, is there some legitimate thing that we can understand? Is it better trenching techniques or something? Is it a technological innovation? Does it have something to do with the metallurgy of the pipe or whatever? Maybe there is some difference there.

The other part of it is that the actual experience in the Lower 48, the last big pipelines that were built in Canada, and these are big, long distance, large diameter pipelines, came out on comparative cost to be a factor of three or four lower than even the $115,000. And it seems to me that again, my engineering instincts tell me that I need to understand why building a pipeline in Alaska is three or four times more costly than building it in the Lower 48. These issues are not trivial because as a legislature you're going to be asked to make decisions – multi-billion dollar decisions. And what that pipeline number is has some real significance in which way that decision may be affected or altered or looked at. So again, we're hopeful that over time, available to the public and for some level of scrutiny is some of the background that kind of goes with these numbers.

The other issue I wanted to broadly flag to you is that with the array of projects on the table, I think it's kind of good to go back to basics and that's why I included this table, which just kind of shows for a whole bunch of different pipe sizes the implied nominal capacity and, more importantly, the implied reserves that go with it. And again, the way you would use this table is if you were looking at a 36-inch pipe, its nominal capacity is roughly 3 billion cubic feet a day and for something – say a 30 year life, would require about 22 trillion cubic feet of reserves to support that type of a pipeline. Now that's a pretty significant consequence. Again, I'm going to show you some of the variations that take place as you vary the reserve but 22 trillion is very close to what is not only known but developed on the North Slope in terms of Prudhoe Bay. The bigger number, 35 trillion we talk about, is what is quote, known but it is not necessarily developed. And again, as a petroleum engineer type, as a former oil company type, I'm not particularly scared by that difference but the bankers might be. The people that you go to borrow money from would look very differently at the 22 trillion cubic feet as opposed to say the 35 or the 50 trillion cubic feet. And, as you can see, it does make some difference in this.

The other thing is that we put together this chart just to try and show you the full range of possibilities. If one wanted to look at a bullet line, for instance to Cook Inlet, if that's the only project that we could see happening within the next several decades, it could be a pretty small diameter pipeline and I'll show you a little more about that in this chart. After the hearing yesterday I went home and, of course, instructed the ANGDA engineering department to get in gear and do some calculations for me. Unfortunately the graphics art department was on vacation yesterday so you have to accept the hand drawn version but at least I do have a scanner and my green graph paper at least is on a PowerPoint slide so.... What this chart is trying to illustrate to you is the fact that as you get to larger and larger pipe sizes, you will always get a lower tariff if the pipeline is full. But if you look at how the decrement of cost goes, once you start to get above 36 inches, you're into a huge pipe anyway and so going huge-huge does not change the tariff, if you will, by a lot.

The other dash lines on here show you what happens if you put in a pipe but you wrong size it and you don't have the ability to flow through it at that. And as you can see, that penalty can add up pretty fast in certain cases. So again, the term I would use is, you know, you got to right size the pipe. You have to make sense of what pipe size you select in terms of what you think the volume is. For instance, if you put in a pipe to handle 4.5 billion cubic feet a day but the market gags for the first five years and can only accept half that volume, there is a very significant increase in the tariff, maybe in the order of 50 cents for that one happening. So again, you have to be very careful that you get it right in terms of reserves, in terms of market volume and everything else. Again, I flag that to you because as a great student of the public record, I will tell you there is nothing out there at this time that tells us about what the market volume for North Slope gas might be. There's nothing you can look at that will tell you whether the market for North Slope gas is say 2 billion cubic feet a day, as one of the Stranded Gas Act applicants has said, or 4.5 as another applicant has said, or 6, as another applicant has said. There's nothing out there on the public record that allows you to look at that difference and it does matter, and it is important. This is a very unsophisticated calculation but 800 miles in this case, by the way, is significant because 800 miles represents roughly the distance from Prudhoe Bay to the Canadian border. It represents roughly the difference between Prudhoe Bay and Valdez and Prudhoe Bay to Cook Inlet. So again, you're looking at a chart, which portrays for different volumes and pipe sizes roughly the pipelining cost or tariff for any of those cases.

Here's an example of the kind of calculations, and again, I've done this with the revenue department's model that Mr. Marks developed and again, you can run cases until you're blue in the face on this. This is just one looking at the reserve assumption for both the LNG project and the highway project. What's interesting is that if you kind of look at the middle line there, if I move about the same amount of reserves through both projects, even though it takes a lot longer in the case of the LNG project, then you would expect roughly the cost of service to be about the same, and that's what the chart, the model, calculates in this case. And it's just a method of looking at the comparison. Again, you can see what happens in the highway project, the bottom right-hand number, if there is not enough reserves. If you build a project thinking there's 50 but only half shows up, that does dramatically change the cost factors.

And then finally I just sort of – because I really don't have maybe the time this afternoon to really participate, I wanted to offer you one thought about - as you kind of look at how tariffs might be built and, again, the advantage of having ANGDA in this whole fray is that we are able to think constructively and creatively about how to make the project work. And frankly, my trips to the Lower 48 and my interactions with a variety of people that kind of quote, represent the market say that Alaska has to find some way to have a little more customer appeal. And I think one of the ways to do that is to look at some conceptual variable tariff methodology, which basically invites the customer to share and help us get over our hurdle, which is low prices and, at the same time, offer the customer what they want, which is some discount at higher prices. And in talks with regulators, this kind of a scheme, conceptually at least, is very appealing to them. And what I've portrayed here is simply, for instance, if the market price, whatever that means, is say $3 or less, basically the customer would be willing to pay an upper floor of $3 and basically there would be for transportation and production a split that was agreed to on that. As the market price went up, there would be a split of who garnered whatever price increases there were here. And as you'll notice here in this case, I've allocated a greater part of the increase to the wellhead than to the gas line or to the transportation charge. And then above a certain point, the gas line charge would fix, basically, at a maximum and then the wellhead would offer some discount to the customer in return. And again, the advantage is that this kind of a scheme would allow you more favorably to borrow money frankly, because by having the customer participate in the form of the guarantee at the low end, which is what the banker worries about, is a very powerful thing because again, these customers tend to have very big asset bases. They have very captured sets of customers. They are using monopolies – regulated monopolies, and all those things. At the high end, very frankly, giving up some discount at the higher prices may be the price of getting all this to go and some scheme like this may work. I don't know. Again, these numbers are for illustrative purposes only and obviously that would be subject to a lot of multi-party discussion and other things so it's just an idea.

Mr. Chairman, with that I'll quit and entertain whatever questions you have. I did include several other sort of handouts and pass outs of other things that are going on or other things that people have said about us or whatever.

SENATOR TOM WAGONER said he was cautioned, during a conversation about FERC controls, to be cognizant that FERC has more of the control over that pipeline and sometimes asserts certain controls over what is put in the pipeline and the delivery point. He asked if that is true.

MR. HEINZE said his personal experience with FERC related to oil pipeline issues but FERC can do just about anything it wants to do. He said sometimes the logic of its decisions is not apparent. He noted that ANGDA's biggest concern right now is that the conditions for getting gas off a big pipeline, the highway pipeline for example, may be very difficult to negotiate, especially with FERC, because [ANDGA] does not have any great standing on a national level. Second, the lost revenues of gas taken off within Alaska would be counted as a cost against the tariff ANGDA is charged, which is of concern. He said that is a fancy way of saying that ANGDA might have to pay the full fare even though it took gas off only one-third of the way down the pipeline. He said he can find no guarantee that Alaska won't find itself in that situation. He offered that ANGDA has proposed that it be an investor in the project, at least for the volume of the gas that it would like to see used within Alaska. That way, ANDGA could provide some protection for the tariff and off-take point within Alaska. He said in the long run, that is an issue that will have to be guaranteed through the Stranded Gas Act and other proceedings. ANGDA's approach continues to be the positive one, and that is by being an investor, which lessens the risk of the other parties and leaves ANGDA in direct control of what happens in Alaska.

SENATOR LYMAN HOFFMAN referred to the ANGDA chart entitled "Benefits to Alaskans" and asked how much work has gone into calculating the feasibility of delivering LNG to the river communities and to barge LNG to the coastal communities.

MR. HEINZE said last Friday he met with the municipal advisory group on the Stranded Gas Act and showed that group, in detail, this benefits analysis spreadsheet. He said one of the major factors would be fuel costs – power cost equalization and the cost of fuel in rural communities and other places. He said that ANGDA is trying to go beyond the "pretty drawing" and is attempting to reduce those benefits to hard numbers. [End of TAPE 04-09, SIDE B]

TAPE 04-10, SIDE A

MR. HEINZE continued by saying second, ANGDA believes that on the rivers, propane may be the better way to meet the energy needs of many rural villages. ANGDA believes gas can be moved to the coastal communities in the form of LNG or compressed natural gas. He explained the reason to liquefy natural gas by cooling it to cryogenic temperatures is that it provides a 600 to 1 volume advantage. It weighs the same but fits in a container 1/600th of the size. Compressing the natural gas to about 2500 psi can reduce the size of the container, and that volume advantage is about 100 to 1. Although the volume advantage is not as great as that of LNG, the cost makes compression a very competitive idea. ANGDA believes that compressed natural gas is certainly a possibility for many of the coastal communities. ANDGA has looked at the idea of barging LNG. A small LNG plant located in Cook Inlet could be the source for the LNG distributed to the coastal communities.

MR. HEINZE said ANGDA has estimated that bringing North Slope gas to the [Anchorage] area will provide about $100 million of disposable income per year in this economy, the equivalent of adding $150 million in payroll. He said ANGDA believes it must be prepared to implement some of the benefits no matter what project goes forward.

SENATOR HOFFMAN said the problem with propane in rural communities is that it is used primarily for cooking, which is not the largest consumptive use. Electricity is generated with diesel and many of the communities would be interested in converting to LNG for heating and to generate electricity. He expressed interest in seeing a comparison of the LNG numbers for heating and electrical generation.

MR. HEINZE replied that compressed natural gas may be an ideal feed for a very efficient gas turbine unit. Almost any clean hydrocarbon fuels, whether ethane, propane, or methane, are very good feeds for anything resembling fuel cell technology. The advantage of propane is that any appliance can run on propane and any hardware store has the gadgets necessary to hook it up. He said right now, the municipal advisory group under the Stranded Gas Act has hired a contractor to look at the total socioeconomic impacts. That study will answer some of Senator Hoffman’s questions about the best fuel source for each community and should be available within a matter of months.

SENATOR WAGONER asked what impact a bullet line from Fairbanks or Delta to Cook Inlet would have on current exploration and production in Cook Inlet.

MR. HEINZE said he provided some background information on Cook Inlet and explained that Cook Inlet is down to 2 trillion cubic feet, while the amount used per year is roughly 200 billion cubic feet. That amounts to a ten-year supply. He commented:

When you get down to a 10-year supply, a lot of things stop working in terms of borrowing money if you're a utility so basically Cook Inlet finds itself in a situation where it probably needs to replace every year just about what it consumes. The good news is that can be done. The bad news is to do it, it's going to cost more money than we pay right now for gas. The replenishment probably has to take place at prices competitive with the Lower 48, because that's what it takes to attract capital to explore for the gas here. If North Slope gas with a very large supply was hooked to this area, it is reasonable to expect that the prices would return to today's levels. Roughly today, the prices are about $2.50 wholesale. It's expected that the new prices, you might say, will eventually – and in about five years that's what we'll pay - is something double that, about $5. The availability of North Slope gas into this area as a large supply would probably take the prices back to $2.50. What it would probably do is discourage exploration in that sense. The exploration that is taking place now, the decisions people are making now, they are selling under long-term contracts at very nice prices.

So, what would I predict? I predict that people who find gas now are going to get a good price for it. Would I predict that they should wait five or six years to go looking? No. I mean if it was me, I'd get on with it right now and be uncertain as to the future.

CO-CHAIR SAMUELS thanked Mr. Heinze and called Mr. Marks to testify. He told members that Mr. Marks has been a petroleum economist with the Tax Division of the Department of Revenue since 1983 and that much of his recent work has focused on analyzing the commerciality of North Slope gas.

MR. ROGER MARKS, Department of Revenue, told members his presentation would focus on the impact of property and corporate income taxes on tariffs. [A paper copy of Mr. Marks's PowerPoint presentation is located in the committee file.] He began:

Just to review on what the elements of a tariff are, a tariff is simply a way of passing through all of the costs and so the pipeline owner can be reimbursed for all of his costs and also make a profit. There are different ways to characterize the costs. I've put them into seven different categories here: capital costs, which are recovered through depreciation over time and include interest during construction and, on the equity part, funds used during construction; operating costs; debt or interest costs; property taxes; state and federal corporate income taxes; and the return on equity, which is the profit element, which we'll discuss in some detail.

So starting out with the property tax on page 3, the property tax administered under AS 43.56 is based on 20 mills, or 2 percent of the remaining value of the pipeline at any point in time. Value is determined based on both a cost or income approach by our assessors. Since it's based on remaining value at any point in time, it starts high and declines. Any piece of property that's within a municipality, they retain their share of the property tax up to their mill rate and the state gets the remainder. In other words if, I believe, the Fairbanks North Star Borough, their mill rate is I think about 15 mills now, so they would get 15 mills, the remaining 5 mills would go to the state.

On the producers' proposed project, the $19 billion project to Chicago, the portion of that in Alaska is about $7 billion, which includes the conditioning plant and the pipeline part. My estimate of the property tax part of that would be about 8 cents on the tariff.

Page 4 – in thinking about the economics of the project and the viability, there are a couple of issues that the property tax presents that are problematic to some extent for the pipeline. The first is that the property tax is what we call front-end loaded. The way we administer the tax through the law, the tax starts accruing as soon as property enters the state, which could be years before it goes into service and starts producing revenue. On the time value of money, paying those taxes reduces the rate of return. And again, the interest and funds used during construction accumulate and are put in part of the tariff base.

The second problem with the property tax is what's called regressive and regressive, in terms of tax terms means that when profits are low, the taxes are a high percentage of the profits and when profits are high, taxes are a low percentage of the profits. The regressivity part creates an economic problem again when profits are low.

In the case of the property tax, one of the big risks of this project is a cost overrun. If there is a cost overrun, not only do you have a cost overrun, but since the property tax is based on value, not only are your costs higher but your property taxes are higher too, which kind of presents a double whammy.

In the Stranded Gas Development Act, a couple of these problems have been presented as issues that could be addressed in negotiations with project sponsors, the idea being there may be a way to modify the property tax. This has naturally created a lot of concern for the local municipalities in terms of their tax base being modified. With the highway project, it would be the Fairbanks North Star Borough and the North Slope Borough who would be affected if the property tax is modified. Per the Stranded Gas Act, it says that if we do develop a contract with the project sponsors, that a fair and reasonable share of the amount of money we take in as a state should be given to both revenue-affected communities, which are ones whose tax base is being affected, and economically-affected communities, ones who are bearing social burdens because of a project, that a fair and reasonable share of the taxes should be given to them with due regard to the amount of the tax base, the amount of the social burdens.

A municipal advisory group has been established for the Stranded Gas Act to address concerns that the local jurisdictions have over modifying the property tax and that group is up and running.

That's really all I have to say about the property tax. I was going to go on to the corporate income tax now on page 5. In understanding the corporate income tax, it's important to sort of understand just what the source of income is that's being subject to the tax and, as we saw back on slide 2, the tariff is made up of several elements and all those elements are costs that are recovered through the tariff. The return equity is not a cash flow cost. What the return on equity represents is an allowance for an opportunity cost for the cost of equity and, again, that represents the income that's subject to the tax.

On page 6, there's an example showing a simple derivation of the return on equity. Just in this example we assume a $500 asset that's 80 percent debt and 20 percent equity so the equity part of it would be $100. And let's just assume it has a 5-year life and it's depreciated, I just assumed for this example, a straight-line depreciation where there's just $20 depreciated each year for 5 years. There are other methods of depreciation that are allowable under FERC methods, depending on whether you want to get a declining tariff or an increasing tariff or a levelized tariff, but just a real simple method for the example here, it's just a straight line depreciation. And so, you can see if you start out with $100 and depreciate $20 each year, the third column shows the undepreciated amount each year and then assuming a return on equity of 10 percent, the return on equity in each year would be 10 the first year, then 8-6-4 and 2. Under long-term capital markets, return on equity would probably be something around 12 percent. It would really depend on just exactly when the pipeline comes into service and what the capital markets are at the time. I just used 10 percent here because it's easier to multiply by 10 percent in looking at these figures.

But this return on equity represents the income that's subject to taxation and I'll just note here with this straight-line depreciation, you get a return on equity that declines each year and this would produce a declining tariff. Again, there are different depreciation methods you can do to have either a levelized tariff or an increasing tariff.

On the debt side there's a mirror image in terms of the tariff also. A similar way to calculate the return on debt, in this case it would be with 80 percent debt it would be a $400 debt that there would be return on debt. The debt would have a lower rate of interest. Again, the long-term capital markets - that would probably be about 8 percent. Again, that depends on just when the pipeline is built and the capital markets at that time. On the debt side of this, what we call the return on equity here, the return on debt would actually be interest payments and those - again, it would be an element in the tariff as well. But this return on equity is not a cash flow cost but represents again the income subject to taxation.

When talking about the state corporate income tax, it's useful to know how it works on page 7. The state corporate income tax – and income taxation in most states is administered by a method that's called apportionment where either U.S. income or worldwide income is apportioned to the state and that becomes the income subject to taxation. The reason states use apportionment rather than an actual sort of cash flow method of measuring income – an example that's used is sort of if you have General Motors producing cars in Michigan and selling them all over the country, it would be very difficult to determine how much the income is determined in each state. So what states do in general is use this method of apportionment where, based on economic factors in the state relative to worldwide, you apportion the worldwide or U.S. income back to the state. With oil and gas in Alaska, the apportionment factors are property sales within the state or for a pipeline it would be gross tariff income, and extraction or production if the company also produces oil or gas. If it's just a plain pipeline company it would be two factors, property and sales.

Moving over to page 8, this is how the apportionment factor in Alaska for oil and gas is determined. It looks at the relative amount of property sales and extraction in Alaska to the world.... There is an error on this. The last fraction should be Alaska Extraction/Worldwide Extraction – not worldwide sales.

But the three factors - Alaska Property, as opposed to the property tax, where the property kicks in when it enters the state with the income tax as property when the asset goes into service. So what we have here is the three fractions, the Alaska part divided by the worldwide part and the average of those divided by three and that gives you a factor. That's sort of the percent of your worldwide activity that's deemed to be in Alaska.

On the extraction part, if there's both oil and gas, the gas is put on the BTU equivalent with oil so it's an apples-apples approach. They just take the thousands of cubic feet and divide by six. That's the mcf of gas and the barrels of oil on an apples-apples basis. Now this is what is called a modified apportionment. Most states, and with non-oil and gas activity in the state instead of extraction, payroll is used but starting in 1981, this modified apportionment has been used. And the other difference again between oil and gas and other activities in the state, the way our corporate income tax works, is with non-oil and gas it's Alaska property divided by U.S. property and Alaska sales divided by U.S. sales. That's called a water's edge approach, just putting a ring fence around U.S. activity and bringing in U.S. income rather than worldwide. With oil and gas, it's a worldwide approach.

Page 9 – so once you know the apportionment factor, the Alaska income is the apportionment factor multiplied by the worldwide income and our corporate income tax rate, I believe once your income is over $100,000 a year, is 9.4 percent so the corporate income tax is 9.4 percent times the Alaska income.

So what does all this mean? Well if this gas project happens, there are seven things that will happen. One, worldwide income will increase. Alaska property will increase. Alaska's extraction will increase. Alaska sales will increase. Worldwide sales will increase. Worldwide extraction will increase and worldwide property will increase. That's a sure thing.

What does this mean? On the income side, again, worldwide income would increase but the way apportionment works, this income is never distinguished between Alaska income and non-Alaska income. That's the whole point of apportionment is that that's difficult to do so it just goes in one big pot called worldwide income and the apportionment factor allocates worldwide income into the Alaska tax base. So, for example, if the Alaska apportionment factor is 10 percent and worldwide income is $100, $10 gets apportioned into the worldwide tax base and that's subject to the 9.4 percent tax rate.

And income generated by the Alaska project is apportioned only to the same extent any other income is so if there's $20 generated by an Alaska project and there's a 10 percent apportionment factor, $2 comes into the Alaska tax base. But if there's $20 generated in Peru, same thing, with the 10 percent apportionment factor, $2 would be apportioned into Alaska. So, again, income is never distinguished between Alaska and non-Alaska in origin.

On the apportionment side, again, the apportionment factor would increase as the result of this project and the [indisc.] apportionment factor would apportion more worldwide income into the state. For example, if we were 10 percent before, the project might make it go to 11 percent. That might not sound [like] much, but you're getting an extra 1 percent of worldwide income. That's quite a bit of money coming into the Alaska tax base.

So for the derivation of the tax rate for the tariff, what does this mean for the tariff? Again, income generated in Alaska is apportioned for taxes everywhere, not just Alaska, but in the tariff, the tariff is designed to recover all of the costs to the company, including the taxes they pay everywhere as a result of tariff income, not just in Alaska.

Now taxes rates are not uniform everywhere. Income could be apportioned to all the other 49 states but they all have their own individual tax rates. They're not 9.4 percent. However, since each state has its own apportionment factor and its own tax rate, it's impossible to determine the exact tax burden that's going to be borne by the pipeline owner. And what regulators generally do is assume, for the piece of property within a jurisdiction, they assume the tax rate in that jurisdiction. So for the piece of pipe that's in Alaska, they would assume a 9.4 percent tax rate.

This just shows sort of the derivation of the corporate income tax allowance in the tariff. The allowance is an after tax allowance and in the example we had back on slide number 6 where we had a 10 percent return on equity, that 10 percent is an after tax return. To get an after tax – you need to recover more before tax to get a 10 percent return after tax. And in that example, with a 10 percent return on equity – let me just go back to slide 6 for a second here, just looking at that first year with a 10 percent return on equity, that $10 is an after tax return. For taxes, the way a pipeline company will pay its taxes, it will receive tariff income for shipping the gas and the tariff times the amount of gas will be its gross income. Then it will subtract its cost and that will be its taxable income and then they'll pay tax on that. Now the tariff gives the pipeline company an allowance to cover the taxes and, in this case, so that they're left with $10 after they pay the tax. So they need to recover more than $10 before tax to be left with $10 after tax and that's done with something called a tax gross-up factor and that's simply the tax rate divided by 1 minus the tax rate and again, with our state, with a 9.4 percent income tax rate, 9.4 divided by 1.94 is 10.38 percent as sort of the effective amount of tax you need to collect before so that you're left with return on equity afterwards. So, if your return on equity target is $10, the state corporate income tax allowance needs to be, in this example, you know, .1038 times 10 or $1.038.

And just in the box here, to see how it works, if your return on equity allowance is $10 and your tax allowance is $1.038, you have $11.038 and when you're computing your taxes if you take 9.4 percent for your tax times the $11.038, that gives you 1.038 and so your return after tax is your total allowance minus a tax allowance, 11.038 minus 1.038, which leaves you with $10. Again, that's what your return on equity was.

Again, this is for tariff making purposes. This is again pro forma, the calculation for the tax allowance. It's different than the actual taxes that will be paid. They'll be paid again subject to apportionment and worldwide income. If this project goes forward there will also be state income taxes on upstream profits that are made from the producers selling the gas. In addition to state corporate taxation, there's also federal income taxation - which there's an allowance for that in a tariff as well. That's computed similarly. The only difference is, again, the feds have a different tax rate. It's at 35

> percent and the state income tax is deductible for the federal tax. My estimate of the Alaska corporate income tax adds about 2 cents to the tariff and the federal side, again, on a $19 billion project, is about 20 cents.
>
> That concludes my remarks and I'd be happy to answer questions if I can. Thank you.

CO-CHAIR SAMUELS said the committee heard yesterday that the amount of risk a pipeline owner has in a project would also be factored into the tariff by FERC. He asked Mr. Marks where he would incorporate that risk on page 2 of his PowerPoint presentation.

MR. MARKS said risk would be explicitly addressed as the return on equity. Generally, pipeline companies need a throughput commitment and a shipper pay commitment to get financing. In a shipper pay commitment, the shipper will commit to put gas in the line and pay to ship it, whether the shipper has the gas or not. That reduces the risk of the project. The 12 percent return on equity is commensurate with that amount of business risk.

With no further questions of Mr. Marks, CO-CHAIR SAMUELS asked Mr. Carruthers to present.

MR. JOHN CARRUTHERS, Vice President of Northern Development at Enbridge, informed members that Enbridge has submitted an application that was approved under Alaska's Stranded Gas Development Act. He said the goal of his presentation is to provide context to some of the questions members have regarding what must happen to the gas once it reaches Alberta. He noted that recently, the Canadian producers could not ship stranded gas out of Alberta due to pipeline constraints. They found the most economical way to move the gas was through Alliance, a new high-pressure liquid-rich system that is consistent with Alaska's needs. Alliance began service in 2001 and was considered to be very successful by the industry. Enbridge worked with producers throughout the process and now owns 50 percent of Alliance. He introduced Jack Crawford, the Chief Operating Officer of Alliance Pipeline and noted that Mr. Crawford has been with Alliance throughout conception, construction, and operation.

MR. CARRUTHERS began by explaining that Enbridge has 50 years of experience in pipeline transmission. It owns and operates the world's largest crude oil pipeline system, which moves crude oil from the Western Canadian sedimentary basin through the Midwest. Enbridge also owns the Norman Wells pipeline; therefore Enbridge is the only pipeline company with extensive experience in the construction and operation of pipelines in continuous and discontinuous permafrost. He continued:

> We also bring a market perspective as the largest gas distribution company in Canada, shown in yellow, but today we want to focus on our experience in completing the Alliance pipeline. Again, it was a response to a consistent situation – pipeline-constrained gas, in this case in Alberta. It's a high-pressure liquid-rich line that transverses both the U.S. and Canada and was permitted efficiently in both Canada and the U.S. That line is shown in red on the map that you have.
>
> I think we can skip forward a bit. I've given some of this information to some of you previously and some of it was discussed earlier. I really want to go to the forecast of Canadian supply. It's going to be very key and this forecast is back a few pages in your presentation. It's consistent with many and shows continuing growing production out of the Western Canadian sedimentary basin although a key consideration is much of this portion of growth is from natural gas from goal. So we do have a huge asset in Canada that parallels that of the United States in terms of size but certainly we haven't developed it nearly as much as the U.S. has. Less that 1 percent of our total production is from gas from coal, in comparison to over 10 percent in the United States, although we have a similar resource. It will require significant capital going forward and, given the decline of traditional reserves, our expectation is that capital will come but it's very important to continue to watch that. Clearly, the key for that in Canada is the use of water, something that has some opposition to the development of coal bed methane but we think there's a significant resource that can be developed.
>
> This graph is very relevant. You'll see a significant decline in the lower portion, which is Alberta conventional. Again, we would see coal bed methane being able to make up a significant portion of that decline. But I think what's more important, this graph is relevant, it's about the time that Alaska gas will

come on in 2012, 2015 period, so it's quite relevant. Really what's important is what will the picture look like going forward from 2015 because we'll have investment in a 30-year asset and we'd like to have consideration.

I think what we're trying to show here is that although we can have forecasts and they're well thought through, there's considerable uncertainty with what actually [it] will look like – what production will look like out of the Western Canadian basin. So it's something that we'll have to have a number of alternatives that we need to consider.

So let's start with where the gas goes today with the capacity of the pipelines. The good news is that there is well-developed infrastructure out of Alberta and there will be competitive options for Alaska gas. There is the potential to fill underutilized capacity. I think Tony will talk to you a little bit about that today. In the red - and these graphs as I mentioned, are relative, TransCanada is the largest – moves much of the gas out of the system. Eastern Gas, as you can see on the graph, handles 7 bcf per day and today you'll see something in the order of 2 bcf per day of spare capacity. As you look at the other pipeline systems, Alliance, Northern Border, Duke are all near capacity and they would have existing shippers with contractual rights.

When you look at the capacities from a producer perspective, which includes royalty owners like Alaska and Alberta governments, you want the pipeline systems to remain below full capacity to avoid bottlenecks and reduce prices. We went through that situation prior to the construction of Alliance and as a producer they saw significantly reduced prices, so you always want to have some extra capacity in your system. You don't want significant underutilized assets, as those have associated costs.

So it does provide good context to understand these systems today but again, you'll have to take that previous forecast and overlay it on these systems to see what they look like going forward. I think you'd also have to be cognizant of what capacity remains going forward. It is possible that certain capacity would be taken out of the system if it's not being utilized so it could be retired so some of the capacity lines could change as well. So it's very important to understand the systems and the capacity of those. It's also important to understand what the contractual commitments are with each of those. As we heard yesterday, there's a number of – the existing shippers will have rights to certain capacity. So again, it would be important to look at the contract [expirations] over the course of development of Alaska gas. As you can see from this graph, many of the contracts expire. Typically they can be renewed on one-year extensions with six months notice. So again, just in terms of consideration of the project and downstream opportunities, people have to be cognizant of what shippers are on what systems and what rights they have. Alliance itself has signed 15-year shipper pay agreements that could expire in 2015.

Again, I think this slide is included just to show that once you reach the Western Canadian sedimentary basin, there is significant optionality out of there to markets across North America and what we wanted to look at was the capacity outlook going forward. I think it's good context to understand what's happening today, what might happen when MacKenzie gas comes on-stream and then look at what might happen once Alaska's gas arrives.

So if you look at the top right hand corner, which summarizes it, I won't go through this entire slide but I think it does provide good context for people to work through. Today the Western Canadian sedimentary basin produces about 17 bcf per day and we export 12. Supply is expected to increase with MacKenzie by 2010 and Alaska gas certainly by 2015. At the same time, Alberta demand will increase largely in response to the oil sands development. So you have to look at the Western Canadian sedimentary basin production, what's coming in from MacKenzie and Alaska, and then what is the internal market within Alberta. So the box immediately below the one in the top right hand corner, we are looking at the pipeline capacity based on the earlier throughput. And today, you'd look at it and say we have something in the order of 3.3 bcf per day of spare capacity, but again, I'd caution you as a royalty owner, you do want some spare capacity. On a practical basis, we think there's more like 1.5 to 2 bcf per day of practical underutilization.

If you work down that line based on the previous forecast, it shows that we need 2.1 bcf per day of new pipeline capacity. Again there are a lot of factors that go into that forecast. It's consistent with most around but you would want something like a 90 percent load factor in order to manage your load. You don't want to be full up against the pipeline utilization. If you take that into account, you need something in the order of new pipeline capacity at 4 bcf per day if you assume Alaska gas is in the order of 5 bcf per day at that time. It could be a situation where you do need a full 4 bcf per day pipeline.

At that amount, Alliance would have the lowest cost option - would be to loop Alliance and would be the most attractive option. But again, that's not the only [indisc.]. You'd still have to look forward past 2015 to what the Canadian sedimentary basin is doing, what's spare capacity. You could have a situation where the more measured approach that Enbridge had proposed might fit better where you have some underutilization of capacity and you build a pipeline that could handle more like 2.5 bcf per day out of Alaska initially with expansion to 5 going forward. Again, there are some scenarios. You'd want to keep your optionality open as developments occur as we get better insight as to whether there is coal bed methane development in Alberta, how the existing basin is progressing, and the timing of Alaska gas. The bottom line is you'd want to maintain optionality.

Clearly, of course, the advantage to not having to build the pipeline out of Alberta is its cost is estimated to be close to $5 billion, so if you can utilize existing capacity, there could be significant advantage.

Some of the key points I think we should be cognizant of that – I mean Alberta should have significant capacity to handle Alaska gas by a phased approach. If you expect 2.5 bcf of spare capacity, if you need a full 4, Alliance would be your most economic option at this point. And then there's ways too, if you don't need it all, you'll see a number of the pipelines that could have a spare capacity and you see a more – potentially PG&E has some spare capacity, Duke has about 200 million, Alliance has 500 million, so you could have a way to make up the needed volumes with a variety of pipes, TransCanada, Alliance, et al.

I think again on this slide – again, I'm not wanting to necessarily go through all of the numbers. Really to take away I think you'll want to recognize in terms of tolls, tariffs – tolls are important but also, of course, the fuel is important, particularly at the high gas prices – from Alaska gas development, high gas prices are positive, in terms of the fuel cost they are not. So you certainly, you know, alternatives downstream you need to look at tolls plus fuel and the other thing that's most important...[END OF TAPE 04-09, SIDE A]

TAPE 04-10, SIDE B

MR. CARRUTHERS continued:

...additional volumes - what the expectation is and what those volumes would be, and what those tolls would be with new expanded volumes, both from a toll and fuel perspective.

So tolls are clearly important but you have to also understand which market you're going to.

Again, some historical reference as to what the spreads have been between Alberta and current markets in the United States. [Indisc.] toll the pipeline and the advantage of going there is an important consideration. You'd need to look at – always in pipeline development you need to look at what happens if you do build a pipeline and what happens if you don't build a pipeline in all scenarios and I think that will dictate where much of this gas will ultimately go. And really, what you'd really want to have, from a resource ownership perspective, is a competitive alternative out of Alberta when it comes and probably, as you heard yesterday, the best way is to have an open season where there are proposals from different proponents and then the market, in the end, ultimately speaks as to which market they want to go to under which scenario because there are different risks associated with the different markets, different scenarios – clearly less risk with utilization of existing pipe.

And I think the other thing is that - it won't drive the pipeline economics but you need to understand the NGL processing considerations. Alberta does face a methane shortage and does want to access the liquids. I'm not aware of any proposals that would not provide access to the liquids. Certainly the producers can [indisc.] contemplated liquids being stripped in Alberta but you can also do it commercially in Chicago. Those seem to be the two preferred alternatives at this time.

So really what we wanted to do was provide a perspective of some of the questions you might think about, some of the ways you might look at that information. But also Jack Crawford joined us because, as I mentioned, Alliance has just been through this process in terms of concept of a pipeline, looking at tolls, tariffs, looking at the regulatory perspective and the financing, and some of the things we talked about yesterday. So certainly we would be willing to answer any questions you have today.

SENATOR BUNDE said he understands the need for competition once Alaska gas reaches Alberta but expressed concern about the "dotted line" between the Alaska border and Alberta. He asked Mr. Carruthers his view of the challenges of building a new line in Canada between the Alaska border and Alberta instead of connecting with an existing pipeline.

MR. CARRUTHERS said the fact that the pipeline will cross a border is no different than other projects Enbridge has recently been involved with. He noted the engineering would be the same and Enbridge would not split the project at the border because there would be no sales there.

SENATOR BUNDE clarified that putting in an Alaska pipeline will require major congressional legislation to solve some Native American issues and he expects Canada to have to deal with some of the same issues with its First Nations peoples. He asked what challenges exist on a national level for Canadians to support a pipeline in that area.

MR. CARRUTHERS said Canada supports the development of natural gas. There was opposition to the production tax credit that was included in the legislation. The provinces support the development as well and the First Nations are supportive of pipeline development but want to assure that they benefit from the pipeline activity and that the environment is respected. He stated:

> But I think your question about the potential for aboriginal delay is very relevant and a good indication would be how the MacKenzie gas pipeline is being developed today and there [are] issues in terms of aboriginal support so it's a very important issue that needs to be considered. Relationships with the aboriginals will be key in Canada to development of the pipeline. But again, I think there's actually support for it, but it will have to be managed well and there is an expectation and a need for the aboriginals to have benefited out of the project.

CO-CHAIR OGAN asked if the Enbridge proposal is to phase in the amount of gas that comes down the highway and whether Enbridge wants to start with a 36 inch pipeline and add another one later.

MR. CARRUTHERS said he thinks consideration needs to be given in comparison to a 48 to 52 inch pipeline, which has the economies of scale and is a very competitive alternative. Another alternative that should be explored is the initial development of a 36-inch pipeline that would bring in the order of 2.5 bcf of gas per day and then subsequently looping another 36-inch line. The second line could be bigger depending on exploration activity and the market but that is a more measured approach that has less risk.

CO-CHAIR OGAN asked if the lines would primarily be buried.

MR. CARRUTHERS said yes.

CO-CHAIR OGAN thought digging two trenches for two pipelines would not be as cost effective as building one trench and putting a bigger line in to start with. He said he would be interested in getting more information on the costs because those costs will increase the tariff.

MR. CARRUTHERS said that is the key consideration. He said as the process goes forward, the commitment for shippers for gas will have to be determined. Clearly, building a larger line would not be useful if the commitments aren't there. The next consideration would be competitiveness of supply. Generally, there is more competitiveness on a more conventional build, which should reduce costs. The third consideration is that fewer funds would be used during construction before any revenue from the pipeline comes in. Enbridge sees less risk in a conventional build so it could be that the expected costs might be less on a 52-inch line. He said the crux of the matter is what commitments have been made to support it and how much risk is involved.

CO-CHAIR OGAN said the state wants to encourage development in the foothills where there are large quantities of gas. With a 36-inch line, that gas could be run for a long time but it would discourage development in other areas. He agreed that too much gas to market in the Lower 48 could affect pricing but he has heard the market will need as much gas as Alaska can produce unless nuclear or coal fired generation plants are built. He said the legislature wants to encourage the development of the frontier areas so it needs to consider how much that development will be delayed if the state starts off with a 36-inch pipeline.

MR. CARRUTHERS said in terms of exploration, there is a scenario in which a loop line would accommodate that better. It may be difficult for explorers to indicate a shipping commitment up front. But the expanded pipeline scenario might facilitate more exploration because companies could come in at the second round and the line could be sized even larger. He added that the phased approach would entail a longer construction period.

MR. JACK CRAWFORD, Executive Vice President, Northern Development, Enbridge, told members part of the flip side of that, in terms of looping, is that development could take place over a period of years. He noted the TransCanada pipeline was expanded in increments over a number of years and that levelized the construction boom in a significant way. He pointed out the Alaska line could be looped in increments if a lot of exploration took place, depending on how much gas was developed. Supply would be matched with transportation capability.

CO-CHAIR OGAN asked Mr. Crawford to explain looping.

MR. CRAWFORD said looping is another term for twinning the pipeline so a single line system today could be twinned by building a second parallel pipeline. Additional capacity could also be garnered by building short sections of loop along sections of the pipe. He noted that Alliance's stations today are 120 miles apart. It could loop 30 miles and then the entire 120 miles over a staged period of time and get additional capacity at each juncture.

CO-CHAIR SAMUELS asked Mr. Crawford if he had a separate presentation.

MR. CRAWFORD said he did not but was available to answer questions.

SENATOR WAGONER asked Mr. Crawford his opinion of how FERC will exercise its authority over the distribution of the product going through the line once the pipeline is built.

MR. CRAWFORD said he shares some of the previous speaker's concerns about some of the things FERC has done over the years that haven't always made sense to him. However, he believes the concern that FERC would divert destinations or significantly impact the market is overblown. FERC has tried to step back and let the market work in the past few years. He believes FERC operates with the philosophy that it would prefer to let the market work rather than to be interventionist and dictate how the market should develop.

CO-CHAIR SAMUELS thanked Mr. Carruthers and Mr. Crawford and asked Mr. Palmer to present.

MR. TONY PALMER, Vice President, Alaska Business Development, TransCanada Pipelines, Ltd., told members there has been some commonality in what a couple of speakers have said with regard to facilities from Alberta to market and integration of facilities rather than constructing a bullet line beyond Alberta. He then began his testimony:

> The Alaska project will be a huge undertaking with large risks for all stakeholders. We believe the project should be limited to the frontier pipeline from Prudhoe Bay to Alberta and, at that point, take an integrated approach from Alberta to market and that will give optimal results for Alaskan and Canadian stakeholders. By integrated, I mean that from the Alberta trading hub, which is the largest trading hub in North America, Alaskan gas will integrate into the existing North American gas pipeline grid and Alaskan gas at that point can flow east or west to markets across North America from San Francisco all the way to New York.

This is a map similar to what I had up yesterday, just to show the integrated approach – a little different color scheme. Actually I see that the color scheme doesn’t actually show up that well on the screen but hopefully it does in your hard copy. You can see the Prudhoe Bay to Alberta system being a new piece of pipe at that point, going to an integrated approach.

You heard this morning from participants from Enbridge and Alliance with regards to their facilities. TransCanada’s facilities within Alberta – we have about 15,000 miles of big inch pipe that you would be integrating into and we have another 9,000 miles of big inch pipe going across Canada or into the United States. We own the pipeline going east from Alberta into eastern Canada and ultimately service markets in eastern Canada and into New York and Boston. We own the piece of the pipeline that goes down, called Northern border, that goes down into Chicago and we own Foothills Pipelines, of course, the Canadian piece that connects to the borders, and we are soon to own what used to be called PGT, which is the line from British Columbia. On the map it’s a greenish line running down to Northern California. It used to be owned by PG&E. It is still currently owned by them. We’re in the process of closing that transaction.

So our ‘B to C’ Proposition has an integration with the TransCanada System at Boundary Lake, which is the dark blue line, as I mentioned, by extending the Foothills prebuild to that point.

Our underlying principle of our ‘B to C’ proposition recognizes that integration with the existing TransCanada system will best serve the interests of all constituents by fully utilizing the extensive natural gas pipeline grid and the spare capacity that exists on that grid today and is expected to continue when Alaskan gas flows.

Our proposal provides the most competitive and flexible economic solution for Alaska producers, Alaska royalty owners, and all affected constituents across a broad range of alternatives, we would argue.

What are key criteria and perspectives to examine when you're constructing a pipeline? Well, normally greenfield pipeline decisions are based on an analysis of routing, volumes, and capital cost. The shortest route with the highest volume and lowest cost would always be the preferred route.

However, there are a number of aspects to integration that we believe provide advantages over the normal distance, volume and capital relationships. Those major factors are volumetric requirements. The Alaska volumes are expected to ramp up over a 5-10 year time frame to 6 bcf/d. Our understanding at this point is that the major North Slope producers would anticipate commencing with a volume in the 4 to 4.5 bcf/day and expand from that volume. I spoke to that yesterday.

The last increment of that volume may depend on exploration and production activity once the pipeline is constructed. If you take 6 bcf/day and multiply that by a 25-year or 30-year life, there are insufficient proven reserves today so you would expect that drilling and other proving up would be undertaken over the course of the life of the project.

The liquids composition of the gas likely will change over this time frame as well. That's normal for a gas project. Because the range of potential outcomes is so broad, and may involve more producers than the initial three Alaska producers, the facilities planning for what's described as B to C, which is from Alberta to market, needs to be flexible.

The facilities planning for total supply, not incremental supply, is a very important factor from Alberta. I addressed some of that yesterday.

The interconnection with the existing grid can occur when the Alaska gas reaches Alberta. The Western Canadian Sedimentary Basin (WCSB) is producing approximately 17 bcf/d and the Mackenzie Delta can be expected to ramp up to 1.5 bcf/d. The additional Alaska gas of 4.0 or 4.5 bcf/d would create a requirement of about 22.5 bcf/d in total. This fundamental assumption drives the integration prospect that you're planning for a 22.5 bcf/d gas supply, not just planning for 4 to 4.5 bcf/d.

We believe that market flexibility will be very important for Alaskan gas. It's important for every other source of gas. They will look to attract and attach to the most attractive market and that market may change over time. Rather than constructing a bullet line to one particular market, we believe there's value for Alaskans as there is for Canadian gas in being connected to multiple markets. The combination of reduced Western Canadian supply and expansions on the existing pipelines driven by market factors prior to Alaskan volumes ramping up will influence the appetite to sign up for new greenfield pipelines from the basin.

Depending upon the marketing strategy and the existing commitments from each producer's portfolio, a variety of commitments may or may not be made. The Alaskan producers do not have to precisely match their additional Alaskan production with downstream market commitments as they may choose to sell some of their Alaskan gas within Alberta. That would be their choice. Clearly, you see today major producers seeking a portfolio of markets and a portfolio of terms and that's generally how they optimize their structure.

So what are the system integration benefits beyond what I've spoken to today? The Alberta system has several unique features that are not immediately evident when examining a map of the pipeline system that give Alberta several advantages.

The Alberta system is not operating at full capacity. You heard testimony from a number of parties yesterday to that effect and I heard that again this morning from the parties from Enbridge and Alliance. However, the Alberta system was partially offloaded by the construction of the Alliance pipeline so you had a facility that was built to match TransCanada's northern border system. Once Alliance was built and there wasn't a subsequent addition to gas supply out of Western Canada, you've effectively offloaded, unfortunately, our system because we had the shorter-term contract and you saw evidence of that this morning. New supply has not been robust enough to refill this capacity. This spare capacity can handle some volumes with no incremental construction costs, no incremental environmental impact. Additional compression can further add volumes with little incremental cost.

The net supply additions and demand requirements on the Alberta system are also shifting. If you look at the map of Alberta, you should be aware that the supply in the northeastern section of Alberta near the oil sands, near Fort McMurray, is declining. That is in addition to having an increase in demand in that region so you have two factors that are unloading the pipeline system on the northeastern section of Alberta and there's likely to be a pipeline constructed by us in addition to our existing facility to connect the northwest part of our province with the northeastern part of the province to meet that incremental demand from gas entering in from either western Alberta or northeastern B.C. That is likely to happen in the next several years. That will also improve the integration benefits for this project. This shift in the system load creates a low-cost addition of incremental capability from the northwest to the southeast portion of the Alberta system.

I'd like to address construction costs. The single largest variable having the biggest impact on the toll, on the pipeline tariff, is the construction cost. You've heard that from a number of parties. The estimation of the costs is influenced by pipe size and by competition for resources if both 'A to B' and 'B to C' are constructed in a two-year time frame with the same pipe size, the same compressors, the same valves. Construction of a smaller sized 'B to C' pipeline, as necessary, with more conventional pipe sizing, not only increases the certainty around the construction cost estimates but reduces the competition for steel mill space that would influence the costs of the A to B portion of the pipeline as well. Clearly there is going to be a worldwide supply of steel pipe for this project. That is going to be a necessity. It's very clear that North American mills can be competitive, however they will not supply 100 percent of the steel pipe for this project. If there's a variation in pipe size to Alberta and away from Alberta, that will bring more competitors to that marketplace, not only in the steel business, but in the valve business as well as the contractors. We think that's to the benefit of all parties.

The roll-in, and I believe that term has been described here before - roll-in simply means an averaging of old costs and new costs, but the roll-in of new capital expenditures with existing capital investment to create a toll charged to shippers also influences the capital obligations. In a rolled-in toll, the incremental capital is proportionally less so the impact of a hot construction market is less in the blended average toll. Clearly, one of the fears that you heard me describe yesterday with regards to a potential cost overrun, is there's real potential on a project of this scale for a hot construction market and that environment can affect capital cost overruns. It's prudent to try to minimize that.

Toll integration – so integrating the toll would also have a mitigating effect on construction costs because the system costs are essentially spent today and will be unlikely to increase over the planning horizon. The tariff design in Alberta has created an expressway toll concept from the northwest portion of the province where the 'B' is, near the British Columbia border, and therefore all the way through to the southern portions of the province of Alberta and into the export market. Therefore future additions are likely to have a smaller toll impact at Boundary Lake.

Another advantage of the Alberta system that is often not appreciated is the volumetric size of our system. System receipts are approximately 11.5 bcf/d today, and the export deliveries are approximately 10.0 bcf/d. So those are volumes in the two and three times the expected Alaska volumes. That's the system you would be integrating into. The size of our system adds tremendous stability to the toll. It changes very slowly, very insignificantly, if you add volumes of gas and variances in volumes are relatively small so the toll does not change significantly.

Just to summarize - our integration model is flexible and it appeals to a broad cross section of market participants. Consequently the regulatory approval for this solution is likely to be less contested and, in fact, supported by more interested parties, a very important factor we would argue.

And a key to the integrated approach is to continually monitor the requirement for facilities and to be poised to gain market support for the timely addition of new facilities.

I would like to address a few scorecard items as to how we compare – our integrated proposition with other alternatives. We believe that an integrated solution is more attractive and will be more attractive to Alaskans and Canadians. It's economically superior to any alternative for an independent pipeline – separate pipeline - from Boundary Lake through a broad range of Western Canadian supply and capacity scenarios. You've heard my testimony as well as others that Western Canadian supply and demand numbers are changing. Our forecasts are changing, have changed over the past two years, and I believe that's common across the industry. We are less optimistic about Western Canadian supply than we would have been two years ago. We also believe that demand will not grow as quickly as we expected. But fundamentally, the gap - the spare capacity in the pipeline is growing and depending on what happens over the next several years, you may or may not be constructing additional facilities away from Alberta to serve Alaska gas. That will depend on what happens with parties' actual forecasts.

One of the key advantages for integration is you can defer the decision on constructing the specifics of pipelines beyond Alberta. The time frame to strike a commercial deal on the project in advance of in-service from A to B – from Prudhoe Bay to Alberta as I described yesterday in my testimony, in our case is seven years so if there's a commercial deal struck next year, we have indicated we can be in service to Alberta by 2012. If you want to be in service by 2012 from Alberta away to whatever market you're seeking from San Francisco east to New York, if you're using existing facilities, clearly that commercial deal can be struck several years later than 2005. If you want to build a new pipeline or some component of the additional volumes needs a new pipeline, you also have a significant time frame lag of approximately two years. You wouldn't have to make the decision on the downstream pipeline increment until about 2007. That's a two-year advantage to see what's happening in the marketplace with supply and demand in Western Canada and also to see what's happening in overall markets. We would argue having additional time is very valuable. It generally means you make a better decision.

So, just to walk through some scorecard items – we think that an integrated approach will provide the highest netback price to producers and royalty gas netback owners at Boundary Lake. The tolls – there will be more stable tolls across a wide range of western Canadian supply and demand forecasts - lowest tolls and fuel compared to alternatives. The TransCanada Alberta system tolls receive an immediate benefit from Alaskan gas. That will be attractive to Canadian producers and that will be attractive to the Canadian government I would argue as well.

Capital and warranty costs – the lowest infrastructure capital cost across different pipe size alternatives away from Alberta.

Lowest warranty capital cost. By warranty capital I mean the commitment cost to commit for pipeline demand charges away from Alberta will be lower because fundamentally the existing pipelines do not require 15 and 20 and 25 and 30 year contracts. As you heard testimony this morning, on existing pipes you can contract for one-year worth of service with renewal rights and continue to roll forward that contract if you wish. You can also get expansions on our system in Alberta with a 5-year contract rather than a 15 to 30 year contract. That has value for parties that are making commitments.

Flexibility – We believe that having access to liquids processing within Alberta will have value. Clearly there may be liquids removed within the state of Alaska. There may be liquids removed within Alberta and there may be liquids removed on the way to market. Having additional access to liquids removal facilities will give Alaskan gas one more opportunity to sell their liquids. You'd be connected to an extremely liquid Alberta hub at AECO, and you also hear another term sometimes called NIT – that's Nova Inventory

Transfer that's on our existing system. That is the most liquid hub today in North America – more liquid than NYMEX.

Easy access to flexible and diverse markets away from Alberta Hub – I think I've addressed that, and the shortest lead-time for capital decisions. I've also addressed that for new capacity away from Alberta.

Risk mitigation – also important - lowest risk of 'hot-market' cost overruns. Spread the downstream risk at the integrated hub by having more participants in new capacity may not require additional downstream facilities, depending on the timing and volume of Alaskan flows, and the existing certificates provide the lowest regulatory risk and fastest in-service.

I would wrap up by indicating that the integrated TransCanada Foothills proposition – Foothills Pipelines is now 100 percent owned by TransCanada. They have held the certificates for constructing the Alaska pipeline project within Canada, including B to C, since 1978. They have met those commitments and still hold those certificates today and, as you would have seen from the map, they have an existing pipeline today called the prebuild that has capacity of about 3.3 bcf/d from central Alberta to the Lower 48 interconnects.

The underlying principle of TransCanada's proposition is integration of Alaskan gas into its existing grid, including the Foothills prebuild. The concepts that originally underpinned the Foothills certificates are still valid today and we would argue the overall public interest will best be served by fully utilizing the extensive natural gas pipeline that currently supports Canadian and American gas consumers.

To conclude, the benefits of integration are many and substantial. The economic advantages in capital and warranty costs will not only provide lower prices to consumers, but also higher netbacks to resource owners. What was true in '78 remains true today, that TransCanada and Foothills can provide the most beneficial products for the development of Alaska reserves.

Thank you for this opportunity to appear at this session today and I'm available to respond to your questions.

SENATOR HOFFMAN asked Mr. Palmer to address any consideration given by TransCanada of the potential benefits of this proposal to Alaskan consumers, in particular to consumers along the river system and coastal communities, and of the spur line.

MR. PALMER said the original project, which TransCanada is a proponent of, always anticipated volumes would be taken off of the line at several locations to connect to Alaskan communities. TransCanada's focus is the main line from Prudhoe Bay through Alaska to market but off takes from the line to serve Alaskan consumers were always contemplated. Valves and connections would be built and Alaskan and other investors would pursue constructing those laterals. He noted the original legislation contains specific language regarding reasonable tolls to Alaskans and making gas available to Alaskans.

SENATOR HOFFMAN thanked Mr. Palmer for addressing benefits to Alaskans as that topic was missing from his presentation.

SENATOR WAGONER asked if the 3.3 bcf/d capacity in the system is additional capacity that is not currently being used.

MR. PALMER said that is currently fully utilized and contracted by Alberta Gas. The project was initially constructed because there was seven years of spare Alberta gas at the time in the 1980s, which subsequently turned out to be more than that. It is fully contracted today, generally on a short-term basis. He believed the remaining terms on those contracts would be one through four years. At the time Alaska gas comes on line, Alaska gas would have that as an alternative, as would Alberta or Western Canadian gas.

The committee took a 15-minute at-ease at 10:45 a.m.

CO-CHAIR SAMUELS announced that Mr. Brena would be the next presenter and that he has represented ratepayers before FERC, the RCA, the APUC and the Supreme Court of Alaska. He has participated in virtually all the major rate proceedings affecting Alaska for the past couple of decades.

MR. ROBIN BRENA, Partner, Brena, Bell & Clarkson, P.C., thanked the chair for his introduction, but said he left out the most important part – that he is from Skagway. He stated that he represents Tesoro, Anadarko and Agrium, but he is not representing anyone today and wants to give the committee his opinion on this topic as a citizen.

> It goes without saying that the vast majority of our resources and our wealth are going to flow through pipeline infrastructure that is monopoly infrastructure. It's absolutely essential to our economic future that this monopoly infrastructure has just and reasonable cost-based rates. Rates in excess of that will result in less development of our resources, less revenue from the resources we do develop and fewer opportunities for manufacturing and value-added jobs in Alaska.
>
> This is something that you've got to get right. I am here today to encourage the state to act to insure that cost-based just and reasonable rates are established for this pipeline infrastructure now and into the future and anything that you can do to help that, I think, would be good.
>
> I have sat through many of the presentations, as you've heard and, were I in your position, I would consider myself to have been 'technocrated' to death. So, what I'm going to try to do is try to bring this home in real dollars and cents and real issues that I think, as a legislator, you should be concerned with in the forming of policy. I thought I'd begin with what the true cost is of not getting this issue right – of not establishing just and reasonable rates. The example that you were encouraged by several participants to consider was an example from history, which is TAPS. It's the first time around, it's a large project; it has a great many similarities to the process. And so, what are the lessons of TAPS?
>
> To date, the TAPS carriers have charged and collected transportation rates that are $12.5 billion over just and reasonable rates. They have charged and collected and earned an additional $10.1 billion in excess of just and reasonable DR&R rates. If you only consider the transportation over-collections of $12.5 billion, the impact to state revenues is $8.5 billion. Framed somewhat differently, our Alaska Permanent Fund, if rates were just and reasonable on TAPS, we'd have $8.5 billion more in it today, if the state would have got

this issue right. It would have a balance of $36.5 billion instead of $28 billion. That is what many of the technical analysts have told you. You've heard it in bits and pieces and percentages, and please ask me to defend those calculations at some point. I would be more than happy to.

With regard to the transportation rate, it was simply done. The RCA has done a comprehensive review of the rates on TAPS. The chair at the time, Thompson, presented to you. She referred you and offered you copies of Order 151, docket P974. In that docket, the commission held that the TAPS carriers had over-collected these amounts of money. All that I've done is take the amounts that the RCA has said is over-collected and plugged in what is the Permanent Dividend annual return - if those funds had rather than being collected by the carriers had not been collected by the carriers. That's 10.3 cents and I contacted the Permanent Fund and got their rates of return for the past 20 years. So, that number is real.

The state got it wrong on TAPS and it's cost us $8.5 billion. Let's get it right this time. There's no excuses for not getting it right this time. To understand how to get it right, you have to understand how the state got it wrong. So, I want to talk about some of these concepts.... If you have an alignment of ownership between production and transportation so that people are paying themselves the tariff rate, then they will charge the highest possible tariff rate they can, because they save a quarter in royalty and severance taxes on every dollar they over-charge themselves. So, their incentives will be to have the highest rates possible while holding their costs down. So, where the rubber meets the road is what is the return component - because the return is they don't have to pay it, they just get it and they save a quarter in taxes for every dollar they over-charge from the state. They also save money because they make that excessive profit from independents that need to use this monopoly infrastructure. So, there is a huge incentive for the producers to own and to control this line and to manage the ownership structure so it stays perfectly aligned with the production interests – and to transfer profitability from their production into their transportation. That is what has happened here.

> That is the game that is afoot and that is the game that we haven't figured out yet, well enough.
>
> Let me say, too, that [END OF TAPE 04-10, SIDE B]

TAPE 04-11, SIDE A

MR. BRENA explained that oversight of regulators didn't work, because the reality of regulatory practice is that someone must ask them to regulate or they will not. All the shippers will be affiliated with the producers and their incentive will have the highest rates. Most shippers will ask for reasonable rates and that leaves only the state or small independents. It's difficult for small independents to carry the ball. He illustrated his point by saying that he represented a client in a rate case and won; the rate was set through negotiation at about $1.25, but his client can no longer ship on that line. The producers will only sell oil to his client at the end of the line.

> It's tough for them to get the oil, because they rely on the oil. It's tough for them to stay on the line if the producers don't want to sell it and allow them to ship it. It's tough because the small independents need cooperation in the field and with the transportation infrastructure in order to survive here. So, don't rely on the small independents carrying the water for the state; the state has to do it.

MR. BRENA said the state settled on the TAPS project and it should have litigated. Many of the assumptions in the settlement were proved wrong, but the settlement didn't have a re-opener clause; so, there was no opportunity for the state to come back in and get something that was fair. He summarized how he thought the state should try to get things right on slide 5.

- Establish clear goals. Ratemaking is not complex and a transparent informed process among all the participants is necessary.
- Properly staff and resource the litigation effort.
- Maximize the state's leverage – the state needs to win a rate case once in a while.

Back to the subject of establishing clear goals, MR. BRENA said cost-based, just and reasonable rates are very simple.

> When it costs somebody to build something, you give them their investment back. Until they get their investment back, whatever their investment is, they get a reasonable return on it. They get to recover their operating costs and a tax allowance. And, that's it. Rates should be based on the cost of providing service.

He cautioned that the first question to be asked with any settlement or any proposal is: Are the rates just and reasonable, cost-based rates? Business people don't want to know the rate will be $1; they want to know the rate will stay linked to the actual costs.

Fair terms and conditions for access for future independents is a major consideration. Independents always come to the party later and develop the marginal fields. They will need access to the infrastructure on a forward-going basis. If the major producers lock the transportation and can control access, the independents will be squeezed out. He encouraged the Legislature to do what it can to encourage transparency of the process and include all financially interested parties. "Everybody needs to be at the table."

MR. BRENA said Professor Witherspoon, one of the foremost experts on pipelines in the nation, drafted the enabling legislation.

> I don't think it's fully appreciated that you are negotiating matters with companies that have more sophistication and greater incomes than most nations. You need to recognize that. So, please devote the resources equal to the task and recognize the task or the cost will be at another $8 billion or $10 billion ten years from now.
>
> Recognize you're negotiating and litigating with certain disadvantages. Like it or not, the state is a political process and there are opportunities to influence the political process that don't go the other way with the other negotiated parties. So, it's important because of your disadvantages in this process to have it be an open process. I think the state should focus on maximizing its [negotiation] and litigation leverage and you have huge amounts of it.

On slide nine, you are the owner of the resource. You can put anything in the lease that you want. It’s your oil; it’s your gas. If there are games being played that you can’t figure out the solution for downstream – if there’s not enough tankage to get our resources to the market for fair prices, if there’s a bottleneck in transportation and monopoly profits being realized, if the independents can’t get the access to field facilities because they aren’t able to negotiate cost-based use of field facilities – those are three major bottlenecks that the state will have to deal with in terms of future public policy. All you’ve got to do is put a sentence in your lease.

The right-of-way. You’re the owner of the transportation corridor. That sentence could be under right-of-way. This infrastructure crosses state land. You have tremendous authority and control over the circumstances under which that is used. Your taxing authority and I won’t emphasize that, but I would hate to negotiate with someone that had the power to tax me. I would not assume I was in a position of strength in that situation. You have the power to tax.

The power to regulate.... I was very interested in the chair’s question from an earlier speaker with regard to state ownership and whether state ownership is appropriate or not. The important thing isn’t whether the state owns or doesn’t own it, setting aside financing opportunities that may exist for a state-owned facility. The issue is whether or not the production interest is aligned with the transportation interest. If, to use an example, BP as a producer has to pay TransCanada or me if I own the pipeline, then you can bet that rate is going to be just and reasonable. If it’s not, BP will go to FERC and get a just and reasonable rate. So, you have control over what the ownership structure of this pipeline should be. Let’s say, for example, you decide you want a third-party owner of that pipeline. If you are able to get third-party ownership of that pipeline, then those rates will be just and reasonable, because then the producers will have a huge incentive that they be just and reasonable and they will beat down FERC’s doors getting a just and reasonable rate.

Avoid litigating against the state's own interests. I'm litigating against the state, I'm trying to get just and reasonable rates for instate shippers and the state is opposing me at every step of the way. The positions they are taking are compromising and undermining their ability to negotiate good settlements and to litigate good settlements in the future. It doesn't make any sense.

Avoid compromising state authority. Last year, you had an opportunity to take a look at HB 277. I can't imagine a more broad-scaled give-away of the state's own authority to regulate these issues than was proposed through HB 277. Please do not compromise your authority – and understand something about your regulatory authority. As Professor Witherspoon drafted the legislation, what he intended is the state have the power that the federal government didn't have. There was no gap between the two. That may be very, very important to you in the future – that there's no gap between the two.

MR. BRENA said the FERC can't force extension or expansion of the pipeline, but the local commission can.

If the federal government doesn't have the authority, under your current act, the state does. That's very, very important. That was very well conceived and thought-out by the Legislature and Professor Witherspoon. Please don't compromise away your own leverage to negotiate and litigate better deals for the state!

Next, win a rate case. You know, if the state's going to run with the big dogs, it has to have more than a bark and the state has never won a rate case. At some point...if you're not able to win in litigation, you're not able to get a good settlement. If the settlement is before a litigation victory, then it's a bad settlement; it's costing you money. In the last settlement, the state knew that. There wasn't a secret about it. The assistant AG said we think we can litigate and get $2.5 billion more out of this deal than what we can get, but we can't get a better deal through settlement. So, they took the settlement anyway. Well, fairly compare the cost results in efficiencies of settling with litigating. I realize it’s popular to bash attorneys; I realize it’s popular to say that litigation is something that should be avoided. Well, 20-years ago you avoided it. You had $35 million into litigation, largely on the wrong issues – I just throw that in as an aside – and you settled. It cost you $8.5 billion. Everyone is trying to avoid litigation. What for? Why didn’t you litigate that to its end? I hope I’m not back 10 years from now talking to a different legislature with a similar message. Don’t just assume that settlement must be done. In these circumstances, it has proved to be the worst result in almost every settlement for the state that I’ve reviewed with regard to rate transportation. I have felt, without exception, that a litigated result would have been far favorable.

The ratemaking strategy that the state is faced with is to make regulation as difficult as possible for as long as possible until the state settles with them. Let me tell you, for example, the last 79 rate filings on the TransAlaska Pipeline system have been rejected as inadequate or not supported – the last 79! All right? They’re not trying to get it right. The local electric company in Skagway makes filings to support its rates every three or four years. They get it right; they know - what we call it a 275A filing – it’s what you’re supposed to file with your testimony to say what your rates are supposed to be. Every small utility and bush company in this state with 5 or 6 employees gets it right. The last 79 filings on TAPS haven’t met that minimum standard. They’re not trying to get it right. So, don’t underestimate the successfulness of not meaningfully participating in the ratemaking process - dragging it along until the state finally settles.

Finally, if I were you, I would like to know what to look for in a future settlement that would come before me, so I just thought I’d tell you.

Indications of a bad settlement – rates are not determined based on standard ratemaking principles. As soon as people start talking about rates different than just and reasonable rates or rates based on the cost of service, then you’ve lost. It’s just a matter of trying to figure out how much and you’ll never figure out how much.

Future access is somehow limited so the people that come late to the party can't get in the party. The people that come late to the party are the people that the state needs to develop their marginal fields and outer fields. They're the independents. After the big puddles of oil and gas are gone, they are the people that are left here developing our marginal fields. If that future is that the infrastructure is controlled by the majors, then the independents are who you're relying on for the exploration, then the state will lose.

Return is not based on investment. Actually, in the TAPS, they gave them a return that was unrelated to investment. Five years before I filed a protest on TAPS, the rate of return on equity for TAPS was over 100 percent per year for the last five years, because it wasn't linked to investment.

Long-term agreements with no re-openers, if their assumptions prove false – I put throughput down there. When you build pipelines, you don't know how much of the resource is really there. So, you need to admit to yourself that you don't know. You also need to admit to yourself that you know less than the people you're negotiating with about what's there. Once you admit those two things, then you're on the way to realizing the limitations that if there are throughput assumptions that go into setting those rates, that if they go out and develop three or four times more resource, that that three or four times more resource isn't flowing through at those set rates because that will result in exorbitant returns. So, if there is a settlement, be sure that it can be reopened if it's needed. If the assumptions prove false - and the state has essentially taken itself and TAPS out of the litigation for 25 years - that's the reason why it's gotten so out of kilter. Many of the assumptions that were made are false and throughput was one of them.

If the settlement that comes before you is so complex that it takes a team of experts a long time to explain it, ratemaking is not complicated – not withstanding you sitting through two days of less than pleasant comment. If you don't understand it, then it's because it's a bad deal. It's not because you're missing something. If the settlement trust process was not transparent, if other parties didn't participate, if certainty is confused with predictability - and that goes back to my earlier point that if you see any kind of set rate rather than a methodology, then you've lost. Then, if what you hear when it's presented [is] the limitations, costs and risks of FERC litigation - FERC litigation is not difficult. FERC has done a lot to streamline its process. It would take 18 months to two years for a rate case on this pipeline to go through and one of the things that people continue to confuse is that it matters what FERC's opinion is. The D.C. Circuit really establishes ratemaking principles, not FERC.

So, the question is how is the settlement consistent or inconsistent with the ratemaking authority that the D.C. Circuit has established that it will use to review FERC.... So, don't have overstated to you the costs or limitations of FERC litigation. Every once in a while, go find out. For a $10 million check, you can go set a just and reasonable rate at FERC in a two-year process and that gives everybody a tremendous amount of predictability because you then will have established what the ratemaking principles that will govern this line through its life will be. One of the real problems with settlement is that you never really know how that line is going to be regulated and oftentimes complex settlements deviate so much that they create their own problems if greater problems than standard ratemaking were allowed to continue. Those are my comments and I'd be happy to answer any questions I can.

CO-CHAIR SAMUELS thanked Mr. Brena for his presentation.

CO-CHAIR OGAN considered Mr. Brena's allegations that the state had been overcharged $12 billion to be serious and asked him to explain what he meant.

MR. BRENA replied that he didn't intend it as an allegation, but the Regulatory Commission of Alaska (RCA) sat through weeks of hearings and Order 151 shows, on a year-by-year basis on spreadsheets, that the over-collections were $9.9 billion through 1996. He added investment return to that - had it not been overcharged. The over-collection happened when the state settled by signing a bad deal when it should have litigated.

CO-CHAIR OGAN said while he appreciated Mr. Brena’s testimony, it might throw a wet blanket on the enthusiasm of people investing in Alaska. He has told investors the best way to avoid this type of thing is to have clear and concise rules upfront.

MR. BRENA agreed and said he thought getting terms and conditions right in the first place would result in greater investment in the state, not less. Tilting the cost of the pipeline infrastructure so that there are excessive returns for it would drive out the independents. The best public policy for the state to adopt is to make sure that the people who build the line get their costs back for building it, get a reasonable return for investing in it and get their cost of operation, which they are entitled to under just and reasonable rates. If they got more than that, it would discourage investment. Fair rules for everybody encourage more investment.

SENATOR DYSON commented that the state needs the best consultants to negotiate with these oil companies that are the biggest corporations employing the best minds in the world.

MR. BRENA emphatically agreed.

SENATOR HOFFMAN stated that the industry should not view this hearing as a wet blanket because they are talking about the state’s resources and legislators need to make sure they are maximized.

CO-CHAIR SAMUELS said the point is to educate legislators with a variety of ideas and to expose the public on the complexities of this issue. He mentioned there would be another hearing in July with entirely different points of view.

MR. BRENA said he would be happy to discuss these ideas with anyone if the legislature thought that would be helpful.

CO-CHAIR OGAN said he favored an alignment between the state and producers with an independent pipeline and both would be interested in having the lowest tariff possible. He thought that would bring the best netback.

MR. BRENA cautioned that there would be many opportunities for misalignment.

> You don’t need complete misalignment, you just need sufficient misalignment so you have a major shipper

> who has an economic incentive in a just and reasonable rate and that can be a single shipper. For example, when BP and Arco merged, Arco's interest was allowed to be acquired by BP. If it weren't, BP would be TAPS' major shipper and there would be just and reasonable rates on TAPS. I just used the merger as an example. A condition of the merger could have been that Arco's interest was acquired by a third-party. Then the state would not be losing $100 million a year right now.

CO-CHAIR SAMUELS thanked Mr. Brena for his testimony and invited Mr. John Carruthers, Vice President, Northern Development, Enbridge, to testify next on how he would move forward on a business plan.

MR. JOHN CARRUTHERS, Vice President, Northern Development, Enbridge, said he wasn't going to forward a proposal, but would reinforce the idea that there are some options for the state to consider. Enbridge has had some success with incentive tolling in Canada in terms of aligning pipeline companies with shippers. Pipeline companies want to maximize revenue, but not at the expense of shippers. Obviously there has to be a fair allocation of costs based on risk assumptions. Shippers often want to align the pipeline companies with incentive at as low a cost as possible.

MR. JACK CRAWFORD, Vice President and Chief Operating Officer, Alliance Pipeline, added that in terms of alignment, he realizes that almost all cost issues are related to capital costs and it's very important to control those. Historically, a regulated pipeline company has the incentive to spend more money because it makes money on what it spends. So, it makes sense to focus attention at the outset on the capital costs. As a consequence, the arrangements that Alliance put in place had incentives to control capital costs. He didn't know if the same incentives would be appropriate here because the risks are different.

> It is pretty much a risk-allocation-type procedure.... It's probably premature to forecast how that might look given there is still a number of factors that are not settled in terms of how the risk would be allocated in the future.

MR. CARRUTHERS added that companies with experience in building pipelines in the Western Canadian sedimentary basin are apt to take more risk in terms of building something if they had done it before. "It's more difficult in Alaska, because there hasn't been an underground pipeline built....” The Alliance pipeline might be able to take more risk because of its recent experience in the area.

> We’ve had some good experience with incentive tolling in negotiations with producers in Alberta. Historically, costs were based on cost of volumes and it became fairly adversarial where it was in opposing interests in terms of estimating costs and estimating volumes. They tended to be adversarial and litigated and you came up with a solution.
>
> We moved from that to looking at incentive tolling where the tolls are separated from the costs and trying to align the shippers with the pipeline companies. So, the results you were trying to obtain – that was how you were rewarded on the attainment of those.

MR. CARRUTHERS said Enbridge had the first pipeline in Canada to negotiate incentive tolling and it had good success. The first agreement was in 1995 for a five-year period. It was renegotiated in 2000 and is being renegotiated again. It has worked well reducing costs for both parties. A lot has been done with cost reduction and the renewed negotiations are focused on providing additional services. Flexibility is needed over time to realign.

MR. CARRUTHERS noted that work still needs to be done on the pipeline tariffs, which need to align with the strategy for commercialization of gas - how it would ramp up and what the shippers’ needs are. While they have heard testimony today that shippers want predictability versus certainty, that’s not consistent with his experience. Experienced companies are able to take more operating risk if they have confidence in their capabilities.

> There’s a trade-off between project rating in terms of AA, AAA, B, whatever and the amount of equity risk that is being taken. So, it’s not like [a company] can always go to one corner of the matrix and pick the lowest cost, because there is certainly more risk, which increases the need for returns and higher equity. As we progress through the design and development of the project, there certainly is a way we can align interests between the shippers and the companies building it.

REPRESENTATIVE BETH KERTTULA said his point about having incentives to control the capital costs is particularly important and asked what some of the incentives would be.

MR. CARRUTHERS replied that Alliance has the most current system.

MR. CRAWFORD related that the Alliance system was constructed on a contract that used 12 percent as a target rate of return realizing that at some point, there was a limit on what the rate of return could be.

TAPE 04-11, SIDE B

REPRESENTATIVE KERTTULA asked him what the rate went up to.

MR. CRAWFORD remembered that it went up to 14 percent, but he would have to check.

REPRESENTATIVE KERTTULA asked how that was measured.

MR. CRAWFORD replied that it was pretty straightforward, but there has to be agreement on the initial estimate.

> When we were going through the open season, we had a capital cost that translated through a number of fixed factors into a rate that customers found reasonable. As long as that was reasonable, then in effect, the capital cost was reasonable. There was a recognition that to the extent that we spent more than what the capital costs were that the rate would be higher than what it would otherwise be, but not as high as it would be if the rate of return stayed the same. Likewise, if we had been successful in inflating the cost estimate and we came in under budget, then we would earn a higher rate of return, but all the shippers would see a lower rate than what they had signed up for in the first place. So, why worry as long as it was acceptable at the target rate? Then, there was a restraint on what ultimately could be considered a rate-based company in over-spending and incentives to minimize costs.

REPRESENTATIVE KERTTULA said that explanation was helpful and added the state has done something similar in some of its rate cases. However, the state has a lot more factors in determining the reasonableness of the costs all the way along rather than just saying it's set.

CO-CHAIR SAMUELS thanked Mr. Crawford and Mr. Carruthers for their comments and asked Mr. Palmer to give his presentation.

MR. TONY PALMER, Vice President, Alaska Business Development, TransCanada Pipelines, Ltd., prefaced his remarks saying he wouldn't address specifics on how he would structure a tariff.

> There are a number of different methodologies used to create gas pipeline tariffs in the United States and Canada. My testimony will focus primarily on a cost-of-service methodology, which is the traditional form for a new long pipeline system with high risks, as this project will see. At the end of my testimony I will discuss a couple of alternatives that could be utilized for a project such as the Alaska gas pipeline.
>
> The initial pipeline from Alaska can be expected to remain regulated by U.S. and Canadian governments. It will be highly capital intensive with route-specific investments that cannot readily be redirected to serve other purposes. Once you lay that steel in the ground, it's very difficult to move it to provide another service. The inherent business risks for a pipeline include development risk, construction completion risk, reserve, credit, operating, etc.... The pipeline will be a contract carrier; that is standard in the gas business.... The regulators in the United States and Canada – FERC in the United States, the National Energy Board in Canada - for commercial matters that determine the types and levels of tariffs, which a pipeline may charge its customers for the services it provides and also the terms and conditions of service. The approved tariffs and terms and conditions attempt to balance the interests of shippers, consumers, other stakeholders and the pipeline investors. It's intended to be a fine balance of interests.
>
> The terms and conditions of service are an integral part of the tariff and must be considered in conjunction with the tariff. Natural gas pipelines are highly leveraged businesses with significant financial risk and lower business risk than many other large corporations. That's the structure. Pipeline companies

generally have higher financial risk because they are highly leveraged and they have lower business risk and that enables them to take on the additional debt. That's the fundamental structure that is the foundation for most pipeline projects.

The Alaska gas pipeline can be expected to commence operations with a high debt ratio in order to minimize the pipeline tariff. You heard testimony yesterday from J.P. Morgan. They gave you some evidence as to how that variation can change the pipeline structure, but the fundamental business risk must be matched with the leverage on the pipe – the debt equity ratio - as well as the returns.

So, the high debt ratio will require a properly secured contract with low business risk for the pipeline. The proposed U.S. energy bill provisions for the Alaska project stipulate that the U.S. government may provide loan guarantees [for] up to 80 percent of the capital costs of the project. Such a loan guarantee would assist the pipeline owners in obtaining the multibillions in debt financing and improve the interest rate and loan terms to the benefit of all project stakeholders. In order to obtain the financing, the pipeline must demonstrate the ability to make payments on its debt, both principle and interest, generally through long-term shipping commitments from credit-worthy customers and by meeting certain debt service coverage covenants and other loan conditions.

MR. PALMER showed the committee a schematic of the equity investment that goes into a project of this scale. It demonstrated that risk capital is advanced by equity investors early in the project and before the debt is invested.

So, the current investment that my company has, as well as others, in this project is 100 percent equity. There is no debt behind the project during the development phase; it is 100 percent equity – all risk capital. Even during construction, that also is a period where you have equity capital. If you have contractual terms resolved at that point, you can start to advance your debt during the construction phase.

Recovery of the equity comes over the life of the project and while he used 20 years for his illustration, it's typically spread over the life of a contract.

> Most new pipes in North America have been structured on a cost-of-service basis and a cost-of-service methodology allows the pipe company to recover all prudently incurred costs for providing transportation service including a fair return on capital investment. This usually results in an efficient use of capital with the lowest possible tariffs. These low tariffs, however, are achieved by minimizing the business risks to the pipeline company. The tariffs are subject to full discovery and are completely transparent to all stakeholders for each component of the cost of service. That cost of service model allows the pipe company to recover its fixed costs in a demand charge to its customers – in other words, unrelated to the actual volumes transported on any particular day....

The variable costs are recovered through a commodity charge, which is related to the actual volumes. His schematic addressed property and income taxes and depreciation rate. The depreciation rate is often a factor that is used on a project of this scale to adjust the variability of the tariff over time. It normally reflects the economic life of the pipeline and allows the recovery of capital, both equity and debt, invested in the pipeline over that life. The traditional model had depreciation rates established on a straight-line basis collecting an even amount of depreciation over the life of the project.

> For large new pipelines that need to compete in the marketplace with existing infrastructure, depreciation rates are sometimes modified to levelize the tariff. This means a lower collection of depreciation in the early years of the project and a higher collection in the later years, much like a residential mortgage schedule for principle repayment.... This method, of course, increases the risk for a pipeline company. Instead of getting an even recovery, an early recovery of your capital, you're moving that to the back. That increases risk. There are a number of other methodologies that have been used over the years instead of cost-of-service for gas pipelines.

MR. PALMER said forms of incentive regulation have been used that apply some degree of sharing between shippers and pipeline owners for both capital costs, operating costs and, occasionally, debt costs.

> Other forms of negotiated rates include a fixed toll model with some or all of the components of cost-of-service fixed for the shipper for some period of time. This methodology provides toll certainty for the customer, but significantly increases the risk for the pipeline company. Changes in inflation, interest rates, equity returns for investments of similar risks, capital cost overruns, operating tax variations in a fixed toll model may not be fully passed through to the customer as would be the case for the cost-of-service methodology. There are definitely merits to different tariff methodologies that can be considered for the Alaska gas pipeline by project stakeholders. A traditional cost-of-service methodology with terms negotiated between the pipe company and the shippers and ultimately approved by regulators will usually result in the lowest tariff over the life of the project as it should have the lowest business risk for the pipeline company, assuming solid transportation contracts with strong credit-worthy customers. However, this methodology increases the risk allocation for the shipper and may not provide the highest value to the shipper. If actual costs differ from estimated costs, then all these changes will be fully borne by the customer in the cost-of-service methodology. That's the way it works. For example, you have current interest rates at extremely low levels. You heard testimony to that effect yesterday from J.P. Morgan. An estimated cost-of-service tariff today would likely use those low interest rates. If the actual interest rates are several percentage points higher at the time the pipeline were actually financed, cost-of-service methodology would insure that 100 percent of those increased costs would be passed through to the customer in their tariff and it works the other way, as well. If interest rates fall, that's a pass-through to the customer. That's not a risk the pipeline company bears in a cost-of-service methodology.... You would have an estimation based on interest rates, inflation and other components. The actuals will be what will show up in people's tariffs. A fixed toll model or other incentive mechanisms shift some or all of the inflation, interest rate return and equity, operating costs, capital costs and capital

cost recovery onto the pipeline company. Capital recovery shifts can imply the pipeline is bearing gas reserves risk in the case where proven gas reserves are insufficient to fill the pipeline beyond the contract term. That may be a risk that the shippers want to bear and it may be a risk that they want the pipeline to bear or some sharing of that risk. This shifting of risk could be beneficial to a shipper that cannot or will not bear the risks inherent in a cost-of-service tariff. A fixed tariff with commensurate lower risks can provide higher value to some shippers despite a higher nominal tariff than would be applied with a cost-of-service methodology.

I'll give you an example in ordinary life – is some of us choose to sign up for a 30-year residential mortgage because we want to know that the price of that interest rate over the life of that mortgage. Others of us choose to go for six-month mortgages. Generally, the six-month mortgage has a lower interest rate. Which is better? Well, it depends on your circumstances and which suits your pistol, in effect, as to how you would like to structure your business. It's not that one is better than the other. Some parties will prefer one and some parties will prefer another. We would suggest that the shippers and pipeline companies and other stakeholders will negotiate the methodology that is best for all parties. North American regulators have been cooperative in recent years in approving negotiated methodologies if sophisticated parties have negotiated arrangements on both sides. So, if you have independent pipeline companies negotiating with sophisticate shippers or other stakeholders, regulators have generally been cooperative in approving those. Transcanada has significant experience in cost-of-service models as well as negotiated or other incentive models and we're ready to negotiate with shippers and other stakeholders on the tariff model which best suites the project, which provides a reasonable reward commensurate with risk for the pipeline and a clear regulatory path to an early in-service date. If customers and other stakeholders want a cost-of-service methodology, that's just fine with our company. If they prefer other alternatives that will shift some risks assuming that there’s a balance of risk and reward, we’re happy to negotiate on those, as well.

CO-CHAIR SAMUELS thanked him for his testimony. There being no further business to come before the committee, he adjourned the meeting at 12:20 p.m.